UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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May 14, 2007

J. V. Parrish (Mail Drop 1023)
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SUBJECT: COLUMBIA GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000397/2007002

Dear Mr. Parrish:

On March 30, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Columbia Generating Station. The enclosed inspection report documents the inspection results, which were discussed on April 9, 2007, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one NRC-identified finding and three self-revealing findings of very low safety significance (Green). All of these findings were determined to involve violations of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as noncited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Columbia Generating Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

Claude E. Johnson

Claude E. Johnson, Chief
Project Branch A
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Docket: 50-397
License: NPF-21

Enclosure:
NRC Inspection Report 05000397/2007002

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-397
License:	NPF-21
Report:	05000397/2007002
Licensee:	Energy Northwest
Facility:	Columbia Generating Station
Location:	Richland, Washington
Dates:	January 1, 2007 through March 30, 2007
Inspectors:	Z. Dunham, Senior Resident Inspector, Project Branch A, DRP R. Cohen, Resident Inspector, Project Branch A, DRP D. Stearns, Health Physicist, Plant Support Branch R. Lantz, Senior Emergency Preparedness Inspector, Operations Branch
Approved By:	C. E. Johnson, Chief, Project Branch A, Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR05000397/2007002; 01/01/2007 - 03/30/2007; Columbia Generating Station; Postmaintenance Testing; Surveillance Testing; Identification and Resolution of Problems; Other.

The report covered a 13-week period of inspection by resident and regional inspectors. Four Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for the failure to provide an adequate work instruction (clearance order) resulting in the failure of three diesel generator room ventilation fans to start when required during a surveillance test of the associated diesel generator, DG-1. This resulted in inoperability of DG-1. Energy Northwest implemented immediate corrective actions to restore the diesel generator to an operable condition and entered the issue into the corrective action program for final evaluation and resolution.

  This finding was more than minor because the finding had an attribute of procedure quality which affected the mitigating systems cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance (Green) because, although DG-1 operability was affected, the licensee restored DG-1 to an operable condition within the technical specification allowed outage time. Additionally, the finding was not associated with a qualification deficiency, did not result in a loss of safety function for a system, and was not risk significant due to external initiating events. This finding had crosscutting aspects in the area of human performance with a resources component because Energy Northwest failed to provide an accurate work package to support planned maintenance. The inadequate work package directly contributed to the resultant loss in control power to the affected DG-1 room ventilation fans, resulting in the inoperability of DG-1. (Section 1R19)

- Green. An NRC identified noncited violation of TS 5.4.1.a for an inadequate battery surveillance test procedure was identified because of the use of a non-conservative specific gravity electrolyte level correction factor. This resulted in the inability of Energy Northwest to properly assess the condition of the station's safety-related batteries to technical specification specific gravity limitations.

Energy Northwest entered the issue into the corrective action program and planned to revise the affected procedures prior to its next use.

This finding was more than minor because the finding had an attribute of procedure quality which affected the mitigating systems cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. Specifically, use of a non-conservative specific gravity level correction factor could affect the ability to adequately monitor the reliability and capability of the station's safety-related batteries. The finding was of very low safety significance (Green) because specific gravity level correction factor was never used during surveillance testing ensuring that historical test data was accurate. Additionally, the finding was not associated with a qualification deficiency, did not result in a loss of safety function for a system, and was not risk significant due to external initiating events. (Section 1R22)

- Green. A self-revealing noncited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified for failure to take prompt corrective actions for conditions adverse to quality to assure the seismic qualification of safety-related electrical disconnects was maintained. This resulted in the subsequent tripping open of a safety-related electrical disconnect used to provide power to a containment isolation valve. Energy Northwest entered the issue into the corrective action program and took action to implement interim corrective actions to verify that seismic qualification of affected electrical disconnects was met.

  The finding was more than minor because the finding affected the capability of safety-related electrical disconnects to reliably remain closed during a seismic event. This affected the equipment performance attribute of the mitigating systems cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance (Green) because the finding was a qualification deficiency confirmed not to result in loss of operability. Specifically, although full qualification of several safety-related disconnects was affected due to potential inadequate past preventative maintenance and hardened lubricant, subsequent verifications by Energy Northwest determined that the affected disconnects were fully latched closed and therefore seismically qualified in the as-found fully latched condition. Additionally, the finding did not result in a loss of safety function for a system and was not risk significant due to external initiating events. This finding had crosscutting aspects in the area of problem identification and resolution with a corrective action program component because Energy Northwest failed to adequately assess operability of affected electrical disconnects. This contributed to Energy Northwest's failure to take prompt corrective actions to ensure full latched closure of the affected disconnects resulting in the subsequent failure of a disconnect. (Section 4OA2.2)

Cornerstone: Initiating Events

- Green. A self-revealing noncited violation of Technical Specification 5.4.1.a was identified for an inadequate procedure which resulted in an inadvertent isolation of shutdown cooling. A procedure step required opening an incorrect electrical power supply disconnect, subsequently causing a decay heat removal suction isolation valve to inadvertently close while decay heat removal was in service. Energy Northwest entered the issue into the corrective action program and implemented corrective actions to revise the affected procedure and to evaluate the extent of condition.

  The finding was more than minor because it was a procedure quality issue that impacted the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors utilized the "Significance Determination Process," Manual Chapter 0609, to assess the safety significance of the finding. Per Appendix G, Shutdown Operations, Table 1, the inspectors determined the finding involved a loss of control due to loss of thermal margin and therefore the finding had potential safety significance greater than very low safety significance. A Phase 2 and 3 analysis was performed by a senior reactor analyst and staff from the Office of Nuclear Reactor Regulation. The Phase 2 and 3 analysis concluded that the finding was of very low safety significance (Green). Assumptions and factors which mitigated the safety significance of the finding are included in Attachment 2. This finding had crosscutting aspects in the area of human performance with a resources component in that operators were not provided with an accurate procedure which directly resulted in the inadvertent isolation of shutdown cooling and interruption of decay heat removal. (Section 4OA5.2)

B. Licensee-Identified Violations.

Violations of very low safety significance, which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

The inspection period began with Columbia Generating Station at full power. The station operated at full power for the entire period with the exception of planned reductions in power to support maintenance and tests.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather (71111.01)

.1 Readiness For Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors completed a review of the licensee's readiness for impending adverse weather involving severe cold and freezing weather. The inspectors: (1) reviewed plant procedures, the Updated Safety Analysis Report, and Technical Specifications to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down sections of the systems listed below to ensure that adverse weather protection features (heat tracing, space heaters, weatherized enclosures) were sufficient to support operability, including the ability to perform safe shutdown functions; (3) reviewed maintenance records to determine that applicable surveillance requirements were current before the anticipated adverse weather condition developed; and (4) reviewed plant modifications, procedure revisions, and operator work arounds to determine if recent facility changes challenged plant operation.

- Standby Service Water Pump Houses and Ponds; January 5, 2007
- Diesel Generator Building; January 5, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors: (1) walked down portions of the risk important systems listed below and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walk down to the licensee's corrective action program to ensure problems were being identified and corrected.

- Reactor Core Isolation Cooling; January 17, 2007
- 125 and 250 VDC Electrical Distribution; February 13, 2007

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors: (1) reviewed plant procedures, drawings, the Updated Safety Analysis Report, Technical Specifications (TS), and vendor manuals to determine the correct alignment; (2) reviewed outstanding design issues, operator work arounds, and corrective action program documents to determine if open issues affected the functionality of the system; and (3) verified that the licensee was identifying and resolving equipment alignment problems.

- Automatic Depressurization System; January 23, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors walked down the plant areas listed below to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the corrective action program to determine if the licensee identified and corrected fire protection problems.

- Fire Area R-7; Residual Heat Removal; C Pump Room; January 23, 2007
- Fire Area RC-13; Radwaste Building; Emergency Chiller Area; January 24, 2007
- Fire Area SW-1; Standby Service Water Pump House 1A; January 31, 2007
- Fire Area SW-2; Standby Service Water Pump House 1B; February 1, 2007
- Fire Area R-1; Reactor Building 522 Elevation; March 8, 2007
- Fire Area DG-1; High Pressure Core Spray Diesel Generator Room; March 16, 2007
- Fire Area R-6; Reactor Core Isolation Cooling Room; March 16, 2007
- Fire Area RC-8; Switchgear Room No. 2; March 16, 2007

The inspectors completed eight samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

.1 Semi-annual Internal Flooding

a. Inspection Scope

The inspectors: (1) reviewed the Updated Safety Analysis Report, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; (2) reviewed the corrective action program to determine if the licensee identified and corrected flooding problems; (3) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (4) walked down the below listed areas to verify, as applicable, the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

- Reactor Building 522 ft level; During the performance of Work Order (WO) 01102206; Establish Freeze Seal for FPC-V-108 Replacement; January 30, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On January 29, 2007, the inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved a loss of high pressure feedwater coupled with a loss of containment air system, main steam isolation valve closure, and emergency depressurization due to low reactor pressure vessel level.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the equipment problems or systems listed below to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the Maintenance Rule, 10 CFR 50 Appendix B, and the Technical Specifications.

- PER 207-0042; E-CB-S/2 Failed to Close During Post Maintenance Testing Following Preventative Maintenance Work on Breaker; January 17, 2007
- Control Room Emergency Chillers; March 8, 2007

The inspectors completed two samples.

b. Findings.

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1 Risk Assessment and Management of Risk

a. Inspection Scope

The inspectors reviewed the assessment activities listed below to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and/or enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures, and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- Circuit Breaker E-CB-S/2 Work and Standby Gas Treatment B Outage; January 18, 2007

- Replacement of High Pressure Core Spray Keepfill Pump, HPCS-P-3; January 24, 2007

- Replace Equipment Storage Pool Drain, FPC-V-108, using Freeze Seal; January 29, 2007

- Shorten Residual Heat Removal Pump 2C Discharge Pressure Switch, RHR-PS-16C, Sensing Line; March 6, 2007

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

.2 Emergent Work Control

a. Inspection Scope

The inspectors: (1) verified that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; and (3) reviewed the corrective action program to determine if the licensee identified and corrected Risk Assessment and Emergent Work Control problems.

- Leakage from Reactor Water Cleanup Regenerative Heat Exchanger, RWCU-HX-1C, and Furmanite Repair; February 16, 2007

- Replacement of DG-1 Output Breaker, E-CB-DG1/7; March 23, 2007

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the Updated Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any Technical Specifications; (5) used the Significance Determination Process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- WO 01102516; CVB-V-1JK Closure Test; January 8, 2007
- CR 2-07-01262; RHR-PS-16C and LPCS-PS-9 are making contact with adjacent wall and associated tubing; February 8, 2007
- WO 01084959; Replacement of Relay SLC-RLY-K6B; February 14, 2007
- CR 2-07-00941; Due to internal leakage in the governor valve servo, the RFW-P-1B may not support startup; February 28, 2007
- CR 2-07-01862; RHR-P-2A Discharge Line ALARA Shielding Scaffold Frame Was Not Adequately Modified in Response to CR 2-06-08965; February 28, 2007

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the postmaintenance test activities of risk significant systems or components listed below for review. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the corrective action program to determine if the licensee identified and corrected problems related to postmaintenance testing.

- WO 01124292; DMA-42-7AA1B C Phase Line Side of Disconnect; December 29, 2006
- WO 01127924; HPCS-LS-1A Replacement; January 15, 2007
- WO 01126993; WMA-AD-54A1 Bent Actuator Linkage; February 21, 2007
- WO 01105673; Leak Check for Crank Case Explosion Cover on Cylinder #3 on DG-ENG-1C; February 28, 2007
- WO 01106995; Verify no leaks at DG3 Diesel Air Pressure Switches; February 28, 2007
- WO 01130603; Shorten Sensing Line for RHR-PS-16C; March 6, 2007

The inspectors completed six samples.

b. Findings

Introduction. A self-revealing Green noncited violation (NCV) of TS 5.4.1.a was identified for the failure to provide an adequate work instruction (clearance order) resulting in the inoperability of a diesel generator. Additionally, a crosscutting aspect in the area of human performance with a resources component was identified.

Description. On December 28, 2006, Energy Northwest tagged out-of-service 480 VAC disconnect, DMA-42-7AA1B, which supplies electrical power to diesel makeup air fan, DMA-FN-12. The maintenance activity was directed by WO 01124292 which was written to investigate and repair a previously identified high temperature measurement on the 'C' phase as compared to Phases 'A' and 'B' of the disconnect. The work activity, in part, prescribed de-energizing power to the disconnect via clearance order D-DMA-FN-12-002, determinating electrical leads to the disconnect, removing the disconnect from the motor control center, and inspecting and repairing, if needed, the 'C' phase bolted lug connection of the disconnect. While DMA-FN-12 was out-of-service, operations' staff declared Diesel Generator (DG) No. 1 inoperable.

Following the repair and termination of previously lifted leads, the clearance order was removed and the fan started restoring DMA-FN-12 to service. After the successful start and run of DMA-FN-12, operations declared DMA-FN-12 and DG-1 operable at 10:20 a.m. Subsequently, operations started DG-1 later that same day per Procedure OSP-ELEC-M701, "Diesel Generator 1 - Monthly Operability Test", Revision 25, to conduct a planned routine surveillance test of the diesel generator. Following the start of DG-1, an equipment operator noted that fans DEA-FN-11, DMA-FN-11, and DEA-FN-52 did not auto start as required with the start of DG-1. Operations declared DG-1 inoperable as a result. An investigation identified that control power circuit breaker, E-PP-7AAA, Circuit 3, in the DG-1 HVAC control panel was tripped open. E-PP-7AAA, Circuit 3, normally provides 120 VAC control power to the three affected fans. Energy Northwest subsequently determined that clearance Order D-DMA-FN-12-002, which was hung to support work on DMA-42-7AA1B, was inadequate in that it failed to secure 120 VAC control power to leads terminated at Points 13 and 14 in the disconnect. Energy Northwest postulated that subsequent determination and termination of those energized leads, as directed by WO 01124292, resulted in an inadvertent grounding of the control power resulting in Breaker E-PP-7AAA, Circuit 3, tripping open and preventing fans DEA-FN-11, DMA-FN-11, and DEA-FN-52 from auto starting. Energy Northwest replaced Breaker E-PP-7AAA, Circuit 3, conducted a surveillance test of DG-1 to verify the auto start capability of the affected fans, and declared DG-1 operable at 12:44 a.m. on December 29, 2006.

Energy Northwest documented the issue in PER 207-0001. During the assessment of PER 207-001, Energy Northwest attributed the cause of the inadequate clearance order to less than adequate verification and peer checking in that the clearance order preparer and reviewer did not adequately review work instructions and drawings associated with the task. Immediate corrective actions included, in part, the replacement of the affected circuit breaker, issuing a lessons learned to operations staff on the inadequacy of the clearance order, and issuing a memorandum to operations personnel reinforcing the importance of the clearance order process.

Analysis. The performance deficiency associated with this finding was Energy Northwest's failure to provide an adequate clearance order, D-DMA-FN-12-002, a type of work instruction, to support planned maintenance on DMA-42-7AA1B as prescribed in WO 01124292. The inadequate clearance order resulted in the inoperability of DG-1. This self-revealing finding was more than minor because the finding had an attribute of procedure quality which affected the mitigating systems cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance (Green) because although DG-1 operability was affected, the licensee restored DG-1 to an operable condition within the technical specification allowed outage time. Additionally, the finding was not associated with a qualification deficiency, did not result in a loss of safety function for a system, and was not risk significance due to external initiating events.

This finding had crosscutting aspects in the area of human performance with a resources component because Energy Northwest staff failed to provide an accurate work package to support planned maintenance on disconnect DMA-42-7AA1B. The inadequate work package (i.e., clearance order) directly contributed to the resultant loss in control power to fans DEA-FN-11, DMA-FN-11, and DEA-FN-52, resulting in the inoperability of DG-1.

Enforcement. Technical Specification 5.4.1.a requires, in part, that written procedures shall be established and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1972. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2, Appendix A, Section 9.a, requires that maintenance that can affect the performance of safety-related equipment should be properly preplanned with documented instructions appropriate to the circumstances. Contrary to this requirement, on December 28, 2006, Energy Northwest implemented an inadequate clearance order resulting in the inoperability of DG-1. Because this finding was of very low safety significance and was entered into the licensee's corrective action program as PER 207-0001, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy (NCV 05000397/2007002-01; Inadequate Clearance Order Results in Inoperable Diesel Generator). Energy Northwest took immediate corrective actions to replace the affected power panel circuit breaker restoring the affected DG-1 room fans to service and returned DG-1 to an operable condition.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, procedure requirements, and Technical Specifications to ensure that the surveillance activities listed below demonstrated that the SSC's tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated Technical Specification operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator data; (13) engineering evaluations, root causes, and bases for returning tested SSC's not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- OSP-CVB/IST-M701; Suppression Chamber-Drywell Vacuum Breaker Operability; January 8, 2007
- OSP-RRC-D701; Jet Pump Operability and Recirculation Loop Flow Mismatch; Revision 8; January 17, 2007

- OSP-ELEC-W101; Offsite Station Power Alignment Check; Revision 13; January 17, 2007

- OSP-SW/IST-Q703; HPCS Service Water Operability; Revision 9; February 2, 2007

- ESP-B11-Q101; Quarterly Battery Testing 125 VDC E-B1-1; Revision 6; February 9, 2007

- OSP-ELEC-M703; HPCS Diesel Generator Monthly Operability Test; February 28, 2007

The inspectors completed six samples (five routine surveillance tests and one inservice test).

b. Findings

Introduction. An NRC identified NCV of TS 5.4.1.a for an inadequate battery surveillance test procedure was identified because of the use of a non-conservative specific gravity electrolyte level correction factor. This resulted in the inability of Energy Northwest to properly assess the condition of the station's safety-related batteries to technical specification specific gravity limitations.

Description. On February 9, 2007, the inspectors reviewed the surveillance test data for the station's safety-related batteries to ensure that the batteries which had been replaced earlier in 2006 were performing acceptably. During the review the inspectors noted that surveillance test procedure, ESP-B11-Q101, "Quarterly Battery Testing 125 VDC E-B1-1," Revision 6, steps 5.5 and 8.5, provided direction for measuring specific gravity of individual battery cells. The steps allowed that, if desired, specific gravity could be level corrected by adding .003 to the specific gravity reading for every 1/8" that electrolyte level is above the midpoint of the low and high level lines indicated on the cell jar, or .003 subtracted from the specific gravity reading for every 1/8" that electrolyte level is below the midpoint. The steps also provided that level correction was not required for specific gravity when battery charging current was less than 2 amps. The inspectors noted that the procedure was changed with revision 5 in 2003 to allow for level correction of specific gravity. The inspectors referenced TS 3.8.6, Table 3.8.6-1, note (b), and the TS bases and noted that the TS bases provided that level correction of specific gravity will be in accordance with manufacturer's recommendations. The inspectors requested the basis of the .003 correction factor from Energy Northwest. Energy Northwest engineering staff provided a letter from the battery vendor to Energy Northwest from 2001 which summarized the results of a battery inspection that the vendor had conducted. In addition to summarizing the inspection results, the vendor also suggested correcting battery cell specific gravity with a .003 correction factor to provide additional margin to TS limitations. However, no basis for the correction factor was provided with the letter. Energy Northwest subsequently requested the battery vendor to provide a basis for a correction factor of .003. However, the vendor was not able to provide any documentation of the basis or justification for a correction factor of .003. Additionally, the battery vendor provided a calculation which concluded that the specific gravity correction factor was +.002 for every 1/8" that electrolyte level was above the midpoint and -.002 for every 1/8" that level was below the midpoint based on battery cell dimensions and parameters.

The inspectors determined that use of a non-conservative level correction factor could result in an inaccurate specific gravity reading for a battery cell. This could result in a cell with a specific gravity which did not meet TS 3.8.6 Category A and B limits to be incorrectly assessed as meeting specific gravity TS limitations. Consequently, TS action statements may not be implemented to determine whether battery performance was compromised or a battery may be determined to be operable when TS operability limits had not been met. Energy Northwest documented the issue in the corrective action program as CR 2-07-02116. Energy Northwest subsequently determined that procedures ESP-B12-Q101, "Quarterly Battery Testing 125 VDC E-B1-2," and ESP-B21-Q101, "Quarterly Battery Testing 250 VDC E-B2-1," also contained the incorrect correction factor. Additionally, Energy Northwest reviewed prior test results and concluded that the specific gravity level correction factor had not been previously used therefore assuring that past battery surveillance test results were accurate. The inspectors reviewed Energy Northwest's extent of condition review as documented in CR 2-07-02116 and identified another surveillance procedure, ESP-BAT-W101, "Weekly Battery Testing," Revision 9, which also contained the non-conservative specific gravity level correction. The inspectors concluded that Energy Northwest extent of condition review was inadequate in that it did not identify all of the procedures affected by the non-conservative specific gravity level correction factor.

Analysis. The performance deficiency associated with this finding was Energy Northwest's failure to provide an adequate surveillance test procedure to ensure that safety-related battery test data was accurate. The cause of the performance deficiency was reasonably within the ability of Energy Northwest to prevent in that Energy Northwest staff did not request or verify the adequacy of the vendor suggestion to level correct battery cell specific gravity by a factor of .003 as described above. This NRC identified finding was more than minor because the finding had an attribute of procedure quality which affected the mitigating systems cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. Specifically, use of a non-conservative specific gravity level correction factor could affect the ability to adequately monitor the reliability and capability of the station's safety-related batteries. The finding was of very low safety significance (Green) because specific gravity level correction factor was never used during surveillance testing ensuring that historical test data was accurate. Additionally, the finding was not associated with a qualification deficiency, did not result in a loss of safety function for a system, and was not risk significance due to external initiating events.

Enforcement. Technical Specification 5.4.1.a requires, in part, that written procedures shall be established and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1972. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2, Appendix A, Section 9.b(2)(q), requires that surveillance tests be written for emergency power systems. Contrary to this requirement, in 2003, Energy Northwest revised procedures

ESP-B11-Q101, ESP-B12-Q101, ESP-B21-Q101, and ESP-BAT-W101 to include a non-conservative specific gravity level correction factor. Because this finding was of very low safety significance and was entered into the licensee's corrective action program as CR 2-07-02116, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy (NCV 05000397/2007002-02; Inadequate Battery Surveillance Test). Energy Northwest plans to revise the affected procedures prior to the next performance of the tests.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, plant drawings, procedure requirements, and Technical Specifications to ensure that the below listed temporary modifications were properly implemented. The inspectors: (1) verified that the modification did not have an affect on system operability/availability; (2) verified that the installation was consistent with the modification documents; (3) ensured that the post-installation test results were satisfactory and that the impact of the temporary modification on permanently installed SSC's were supported by the test; (4) verified that the modifications were identified on control room drawings and that appropriate identification tags were placed on the affected drawings; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that licensee identified and implemented any needed corrective actions associated with temporary modifications.

- Temporary Modification Request 06-01; Temporarily remove end cap sprinkler head which was activated due to a steam leak in the Turbine Building 501 foot elevation which resulted in elevated localized temperatures near the sprinkler head; February 01, 2006 through May 15, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector performed an in-office review of Revision 46 to the Columbia Generating Station Emergency Plan, submitted in January 2007. This revision added the description of a security-based drill in response to NRC Bulletin 2005-002, and made multiple administrative changes in response to RIS 2005-13, "NRC Incident Response and the National Response Plan," including a definition of Incident of National Significance. The revision also corrected descriptions of the control room and Technical Support Center ventilation systems.

The revision was compared to the previous revision, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, and to the standards in 10 CFR 50.47(b) to determine if the revision was adequately conducted following the requirements of 10 CFR 50.54(q). This review was not documented in a Safety Evaluation Report and did not constitute approval of licensee changes, therefore the revision is subject to future inspection.

The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the below listed drills and simulator-based training evolutions contributing to Drill/Exercise Performance (DEP) and Emergency Response Organization (ERO) Performance Indicators, the inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and Protective Action Requirements (PAR) development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and (3) determined whether licensee performance is in accordance with the guidance of the NEI 99-02 document's acceptance criteria.

- Plant-wide emergency response organization training drill which included an indication of a small fuel failure, a large condensor tube leak, a manual scram with failure of all control rods to insert, an MSIV failure to close, a RCS leak to the drywell, an unisolable main steam rupture, failure of RCIC and a small radioactive release to the environment; March 6, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Control To Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and worker adherence to these controls. The inspector used the requirements in 10 CFR Part 20, the technical specifications, and the licensee's procedures required by technical specifications as criteria for determining compliance. During the inspection, the inspector interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspector performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator events and associated documentation packages reported by the licensee in the Occupational Radiation Safety Cornerstone
- Controls (surveys, posting, and barricades) of three radiation, high radiation, or airborne radioactivity areas
- Radiation work permits, procedures, engineering controls, and air sampler locations
- Conformity of electronic personal dosimeter alarm set points with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms
- Self-assessments, audits, licensee event reports, and special reports related to the access control program since the last inspection
- Corrective action documents related to access controls
- Licensee actions in cases of repetitive deficiencies or significant individual deficiencies
- Radiation work permit briefings and worker instructions
- Adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination control during job performance
- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas
- Controls for special areas that have the potential to become very high radiation areas during certain plant operations
- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

The inspector completed 15 of the required 21 samples.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector assessed licensee performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspector used the requirements in 10 CFR Part 20 and the licensee's procedures required by technical specifications as criteria for determining compliance. The inspector interviewed licensee personnel and reviewed:

- Current 3-year rolling average collective exposure
- Site-specific trends in collective exposures, plant historical data, and source-term measurements
- Site-specific ALARA procedures
- Three work activities of highest exposure significance completed during the last outage
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- Intended versus actual work activity doses and the reasons for any inconsistencies
- Interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling, and engineering groups
- Integration of ALARA requirements into work procedure and radiation work permit (or radiation exposure permit) documents
- Person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements
- Shielding requests and dose/benefit analyses
- Assumptions and basis for the current annual collective exposure estimate, the methodology for estimating work activity exposures, the intended dose outcome, and the accuracy of dose rate and man-hour estimates
- Exposure tracking system
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding

- Records detailing the historical trends and current status of tracked plant source terms and contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry

- Source-term control strategy or justifications for not pursuing such exposure reduction initiatives

- Specific sources identified by the licensee for exposure reduction actions, priorities established for these actions, and results achieved since the last refueling cycle

- Self-assessments, audits, and special reports related to the ALARA program since the last inspection

- Resolution through the corrective action process of problems identified through post-job reviews and post-outage ALARA report critiques

- Corrective action documents related to the ALARA program and follow-up activities, such as initial problem identification, characterization, and tracking

- Effectiveness of self-assessment activities with respect to identifying and addressing repetitive deficiencies or significant individual deficiencies

The inspector completed 20 of the required 29 samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

Cornerstone: Initiating Events

The inspectors sampled licensee submittals for the performance indicators listed below for the period from first quarter 2006 through the fourth quarter 2006. To verify the accuracy of the data reported during that period, definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 4, were used to verify the basis in reporting for each data element. The inspectors compared the data with operator logs, maintenance records, and corrective action documents to evaluate the performance indicators for the period of January 1 through December 31, 2006. The inspectors verified that the licensee calculated the performance indicators in accordance with NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2.

- Unplanned Scrams per 7,000 Critical Hours

- Unplanned Power Changes per 7,000 Critical Hours

- Scams with Loss of Normal Heat Removal

The inspector completed three (3) samples in this conerstone.

Cornerstone: Occupational Radiation Safety

Occupational Exposure Control Effectiveness

The inspector reviewed licensee documents from August 1, 2006, through March 1, 2007. The review included corrective action documentation that identified occurrences in locked high radiation areas (as defined in the licensee's technical specifications), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned personnel exposures (as defined in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Revision 4). Additional records reviewed included ALARA records and whole body counts of selected individual exposures. The inspector interviewed licensee personnel that were accountable for collecting and evaluating the performance indicator data. In addition, the inspector toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled. Performance indicator definitions and guidance contained in NEI 99-02, Revision 4, were used to verify the basis in reporting for each data element.

The inspector completed the required sample (1) in this cornerstone.

Cornerstone: Public Radiation Safety

Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

The inspector reviewed licensee documents from August 1, 2006, through March 1, 2007. Licensee records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded performance indicator thresholds and those reported to the NRC. The inspector interviewed licensee personnel that were accountable for collecting and evaluating the performance indicator data. Performance indicator definitions and guidance contained in NEI 99-02, Revision 4, were used to verify the basis in reporting for each data element.

The inspector completed the required sample (1) in this cornerstone.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Review of Items Entered into the Corrective Action Program:

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed screening of all items entered into the licensee's corrective action program. This was accomplished by reviewing the description of each new corrective action document and periodically attending daily management meetings.

b. Findings

No findings of significance were identified.

.2 Annual Sample - Seismic Qualification of Electrical Disconnects

a. Inspection Scope

On December 27, 2006, the inspectors reviewed PER 206-0603, dated November 3, 2006, which documented that the electrical disconnect, RRC-42-7BA6D, for the 1B reactor recirculation pump seal line containment isolation valve, RRC-V-16B, had tripped open. As a result of the disconnect tripping open, RRC-V-16B was not capable of being remotely closed as required to perform it's primary containment isolation function. The inspectors reviewed Columbia Generating Station's evaluation of the issue considering: 1) accurate identification of the problem; 2) evaluation of operability and reportability; 3) consideration of extent of condition and previous occurrences; 4) prioritization of the resolution; 5) assessment of the apparent and contributing causes; and 6) adequacy of corrective actions.

The inspectors completed one sample.

b. Findings and Observations

Introduction. A self-revealing NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" was identified for failure to take prompt correct actions for conditions adverse to quality to assure the seismic qualifications of safety-related electrical disconnects were maintained. Additionally, a crosscutting aspect in the area of problem identification and resolution with a corrective action program component was identified.

Description. The inspectors reviewed Energy Northwest's evaluation of PER 206-0603 and noted that the evaluation referred to PER 205-0499, dated July 26, 2005, for a similar tripping open of the electrical disconnect for the B reactor protection bus motor-generator set, RPS-DISC-8A2C. The inspectors noted that in both PER's that Energy Northwest concluded that hardened lubricant in each disconnect was the likely cause of the disconnects inadvertently tripping open. Proper maintenance and lubrication of the disconnects was critical to ensuring that a disconnect would properly latch close during normal manual closure to ensure that seismic qualification was maintained (see IR 05000397/2004003, Section 4OA2.2 for a related finding associated with inadequate maintenance practices on electrical disconnects and the impact on seismic qualification). One of the immediate corrective actions that Energy Northwest previously implemented when inadequate disconnect maintenance was suspect was to perform a verification of the full latch closed position of the disconnect assuring seismical qualifications were met and to hang caution tags on the affected disconnects to ensure that the affected disconnects were verified fully latched closed until proper preventative maintenance could be performed.

The inspectors noted in PER 205-0499 that the failure of RPS-DISC-8A2C to remain closed was inadequate preventative maintenance which resulted in hardened lubricant causing the disconnect to not fully latch close and to subsequently trip open unexpectedly. The extent of condition was determined to be limited to disconnect switches which had not had specific regular preventative maintenance performed in accordance with PPM 10.25.187, "Motor Control Center Starter (Bucket) Maintenance," Revision 10. Corrective actions included scheduling the performance of PPM 10.25.187 on disconnects whose maintenance history did not clearly indicate that the disconnect had been properly inspected, cleaned, and lubricated within the appropriate periodicity. Disconnect RRC-42-7BA6D was identified in PER 205-0499 as a susceptible disconnect which had been scheduled for preventative maintenance during the upcoming refueling outage scheduled to start in May 2007.

The inspectors noted that although Energy Northwest scheduled preventative maintenance for the affected disconnects, operability was not assessed to ensure that seismic qualifications were maintained pending the final completion of PPM 10.25.187. As a result, interim corrective actions to verify the full closure of the affected disconnects was not done and resulted in the subsequent tripping open of disconnect RRC-42-7BA6D as discussed above. The inspectors determined that given the failure of RRC-42-7BA6D and the loss of seismic qualification that Energy Northwest's scope of corrective actions as provided in PER 205-0499 were narrowly focused and did not address the immediate concern of seismic qualification of the affected disconnects. The inspector noted that Energy Northwest staff, in parallel, independently identified the same concern. Energy Northwest documented the concern in PER 207-0020 and identified 20 additional disconnects that had questionable seismic qualification due to suspected inadequate preventative maintenance and the potential for hardened lubricant. Energy Northwest subsequently verified full latch closure of the disconnects to confirm that the disconnects would not inadvertently trip open during a seismic event.

The inspectors considered the failure to assess disconnect operability in PER 205-0499 as a missed opportunity to inspect and ensure that the affected disconnects were properly latched closed and to take prompt interim corrective actions. The inspectors also noted that Energy Northwest's evaluation of PER 206-0603 did not identify as a contributing cause to the tripping of disconnect RRC-42-7BA6D that operability had not been assessed when the disconnects maintenance history was questioned in PER 205-0499. The inspectors considered this to be another missed opportunity to promptly identify the operability concerns associated with the remaining disconnects.

Analysis. The performance deficiency associated with this finding was Energy Northwest's failure to take prompt corrective actions for conditions adverse to quality associated with inadequate preventative maintenance and the affect on seismic qualifications of electrical disconnects as described in PER 205-0499. This self-revealing finding was more than minor because the finding affected the capability of safety-related electrical disconnects to reliably remain closed during a seismic event. This affected the equipment performance attribute of the mitigating systems cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance (Green) because the finding was a qualification deficiency confirmed not to result in loss of operability. Specifically, although full qualification of several safety-related disconnects was affected due to potential inadequate past preventative maintenance and hardened lubricant, subsequent verifications by Energy Northwest determined that the affected disconnects were fully latched closed and therefore seismically qualified in the as-found fully latched condition. Additionally, the finding did not result in a loss of safety function for a system and was not risk significance due to external initiating events. This finding had crosscutting aspects in the area of problem identification and resolution with a corrective action program component because Energy Northwest failed to adequately assess operability of affected electrical disconnects in PER 205-0499 in a prompt manner. This contributed to Energy Northwest's failure to implement adequate interim corrective actions to ensure full latched closure of the affected disconnects resulting in the subsequent failure of disconnect RRC-42-7BA7D prior to adequate preventative maintenance being performed.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," required, in part, that conditions adverse to quality, such as deficiencies and nonconformances are promptly identified and corrected. Contrary to this requirement, on July 26, 2005, and on November 3, 2006, Energy Northwest failed to assess operability of other electrical disconnects identified as susceptible to similar deficiencies during an extent of condition review as discussed in PER 205-0499 and PER 206-0603. This resulted in the failure to take immediate corrective actions to verify that affected disconnects were fully latched closed ensuring seismic qualification was maintained in the interim until proper preventative maintenance could be performed on the affected components. Because this finding was of very low safety significance and was entered into the licensee's corrective action program as PER 207-0020, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy (NCV 05000397/2007002-03; Inadequate Immediate Corrective Actions for Electrical Disconnect Deficiency). Energy Northwest took immediate corrective actions to verify that the affected disconnects were latched closed pending the completion of adequate preventative maintenance.

.3 Cross-References to PI&R Findings Documented Elsewhere

Section 4OA2.2 describes a finding for the failure to adequately assess operability of electrical disconnects that had been suspected of not being adequately maintained. This resulted in inadequate interim corrective actions being implemented.

.4 Radiation Protection

The inspector evaluated the effectiveness of the licensee's problem identification and resolution process with respect to the following inspection areas:

- Access Control to Radiologically Significant Areas (Section 2OS1)
- ALARA Planning and Controls (Section 2OS2)

No findings of significance were identified.

4OA3 Event Follow-up (71153)

.1 Circulating Water Bay Level Transient

a. Inspection Scope

On January 3, 2007, circulating water bay 'A' level dropped below allowable operating limits established by Energy Northwest. Water level lowered following a shutdown of circulating water Pump 1C to support maintenance due to an excess buildup of debris on the 'A' circulating water bay screen. The inspectors observed operator actions from the control room to evaluate the adequacy of the operators' response to the level transient. To assist in recovering level, operators secured plant service water Pump 1A and reduced reactor power to 90 percent. Water level recovered shortly thereafter. The inspectors observed shift briefings, communications and actions in response to the level transient and for reducing reactor power.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 (Closed) Unresolved Item (URI) 05000397/2006004-02; ASME Code Testing of Service Water Siphon Line

This URI was opened pending the NRC's evaluation of the resolution to CR 2-06-06306 to determine if any violations of NRC requirements occurred. Energy Northwest wrote CR 2-06-06306 to determine whether periodic inspections of the service water spray pond siphon line should be performed to ensure reliability of the line. Additionally, the inspectors reviewed the final evaluation of CR 2-06-05951 which documented the concerns related to not testing the buried portion of the siphon line in accordance with ASME code testing.

In October 2006, Energy Northwest requested that an ASME code committee provide an interpretation of Section XI of the code to determine whether or not the siphon line should be excluded from examination because Energy Northwest considered the line to be an open ended discharge line. The code committee determined that although the siphon line was an open ended pipe that it was prudent to not exclude the siphon line from examination because the line did not function strictly as a discharge line. Depending on the operating mode, the line provided both a suction and a discharge path. Energy Northwest concluded that based on the code committee interpretation that the buried portion of the siphon line was required to be included in the ISI test plan and was required to be examined in accordance with ASME Section XI. Energy Northwest also requested the code committee to provide an interpretation of whether the ASME code required testing or inspection of the submerged portions of the siphon line which were not buried. The code committee determined that the ASME code was silent with respect to the need to test or examine the submerged portions of the siphon line and therefore was excluded from ASME code inspection requirements. The inspectors reviewed the code committee's and Energy Northwest's evaluation of the code requirements and determined that the code committee's interpretation was satisfactory.

The inspectors determined that the exclusion of the buried portion of the siphon line from the ISI plan and ASME code testing was a minor violation of 10 CFR 50.55a(g)(4) which requires, in part, that throughout the service life of a boiling water-cooled nuclear power facility, components which are classified as ASME Code Class 3 must meet the requirements set forth in Section XI of editions of the ASME code. Contrary to this requirement, Energy Northwest, since initial operation of the facility, failed to include the buried portion of the service water pond siphon line in the station's ISI plan. However, the violation is of minor safety significance because Energy Northwest had conducted testing which met the intent of the requirements of the ASME code for buried pipe during quarterly in-service surveillance testing designed to test the standby service water pumps. The buried portion of the siphon line was determined to have successfully passed the required exam during the quarterly tests. Energy Northwest planned to included the buried portion of the siphon line in the ISI plan. Additionally, although the submerged portion of the siphon line was excluded from ASME code testing, Energy Northwest concluded that it was prudent to conduct a detailed non-destructive exam of the entire siphon line to assure that the integrity of the line was acceptable. The inspectors noted that Energy Northwest planned to inspect the siphon line as documented in WO 01130651. This URI is closed.

.2 (Closed) URI 05000397/2006005-01; Loss of Shutdown Cooling

a. Inspection Scope

The inspectors opened this URI pending the final evaluation the cause of loss of shutdown cooling which occurred on November 3, 2006, during a forced outage to determine if a performance deficiency existed, and evaluation of safety significance associated with any performance deficiencies. The inspectors reviewed Energy Northwest's evaluation of PER 206-0602 which documented the loss of shutdown cooling event to determine the cause of the event.

b. Findings

Introduction. A self-revealing NCV of TS 5.4.1.a was identified for an inadequate procedure which resulted in an inadvertent isolation of shutdown cooling and interruption of decay heat removal. This finding had crosscutting aspects in the area of human performance with a resources component in that operators were not provided with an accurate procedure which directly resulted in the isolation of shutdown cooling.

Description. On November 3, 2006, during a forced outage with shutdown cooling in operation in Mode 4, operators implemented Procedure PPM 2.7.6, "Reactor Protection System," Revision 23, to transfer the Reactor Protection System (RPS) B to its alternate power supply to support a maintenance activity. Step 5.9.6 provided the following:

"If transferring RPS-B to **ALT B** or **NORMAL**,"
AND maintaining RHR in Shutdown Cooling,
THEN **VERIFY** the disconnects are OPEN for the following valves per SOP-RHR-SDC-BYPASS: Otherwise, N/A.

- RHR-V-8 (RHR-42-S21A7B)
- RHR-V-9 (RHR-DISC-V/9)
- RHR-V-53A (RHR042-7BA5B)
- RHR-V-53B (RHR-42-7BA8C)

The intent of the step was to allow the operating residual heat removal (RHR) pump, RHR-P-2B, to remain running to ensure that shutdown cooling was not interrupted during the transfer. Energy Northwest completed the transfer of RPS B at 3:02 a.m. At 3:09 a.m., while restoring the RHR system, shutdown cooling inboard suction valve, RHR-V-9, disconnect, RHR-DISC-V/9, was closed per PPM 2.7.6, Step 5.9.17. Operators noted that Valve RHR-V-9 automatically closed when power was restored to the valve resulting in a trip of Pump RHR-P-2B and loss of shutdown cooling. Energy Northwest operators entered ABN-RHR-SDC-LOSS and ABN-LEVEL." Operators removed control power fuses for pump RHR-P-2B and performed a vent and fill verification per Procedure OSP-RHR-M102. Valve RHR-V-9 logic was reset and the Pump RHR-P-2B breaker was reclosed, restoring shutdown cooling at 3:54 a.m. At the time shutdown cooling was lost, reactor pressure vessel level was + 70 inches with reactor coolant system temperature at 114 °F. At the time that shutdown cooling was restored, operators noted that reactor pressure vessel level had increased to + 95 inches and that reactor coolant system temperature peaked at 148 °F. Operators subsequently restored reactor vessel level and system temperature to the previously maintained operating bands of 60-80 inches and 110-120 °F at 4:51 a.m.

Energy Northwest concluded that the root cause of the event was that PPM 2.7.6, Step 5.9.6, was inadequate in that it contained a procedure step derived from inaccurate technical information in SOP-RHR-SDC-BYPASS, "Bypassing RHR Shutdown Cooling Isolation Logic in Mode 4 and 5," Revision 1. Specifically, PPM 2.7.6, Step 5.9.6, incorrectly directed opening RHR-DISC-V/9 to ensure that RHR-V-9 remained open. Although opening disconnect RHR-DISC-V/9 secured power to the valve operator of RHR-V-9, it did not prevent the formation of a sealed-in closure signal which was created when RPS B was transferred to its alternate power supply. Instead, the procedure should have directed opening disconnect RHR-42-8BA2A. Opening RHR-42-8BA2A would have secured power to RHR-V-9 and prevented the formation of a sealed-in close signal to RHR-V-9.

Analysis. The performance deficiency associated with this finding was Energy Northwest's failure to provide an adequate procedure in accordance with TS 5.4.1.a. Specifically, Procedure PPM 2.7.6, Step 5.9.6, was inadequate in that it directed opening an incorrect electrical disconnect for Valve RHR-V-9. As a result, Valve RHR-V-9 inadvertently closed when the electrical disconnect was later closed per procedure resulting in an inadvertent isolation of shutdown cooling. The inspectors determined that the finding had more than minor safety significance because it was a procedure quality issue that impacted the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. As defined in Inspection Manual Chapter (IMC) 0609, Appendix G, "Shutdown Operations SDP," this was a loss of control event. Specifically, the performance deficiency involved a loss of the thermal margin following an interruption of RHR greater than 20 percent of the temperature to boiling. Performance deficiencies involving a loss of control event require quantitative assessment (Phase 2 SDP evaluation) in accordance with IMC 0609, Appendix G.

Details of the Phase 2 SDP evaluation and a Phase 3 SDP analysis are documented in Attachment 2. The analysis required the support of a regional senior reactor analyst and risk analysts from the Office of Nuclear Reactor Regulation. To support this effort, the analysts collected and reviewed several licensee documents (referenced in the Attachment) and conducted a site visit to interview appropriate members of the licensee's staff. The SDP Phase 3 analysis concluded that the finding was of very low safety significance (Green). The dominant core damage sequence contributing to the increase in risk for the loss of shutdown cooling event involved operators unsuccessfully accomplishing the following tasks: recovering normal shutdown cooling, initiating alternate shutdown cooling, initiating emergency core cooling, initiating suppression pool cooling, and initiating containment venting. The analysts also concluded from their review that the finding was not significant with respect to large early release frequency because of the significant delay-time to containment failure associated with the dominant core damage sequence. This finding had crosscutting aspects in the area of human performance with a resources component in that operators were not provided with an accurate procedure which directly resulted in the isolation of shutdown cooling.

Enforcement. TS 5.4.1.a requires, in part, that written procedures shall be established and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2, Appendix A, Section 4.y, requires that specific operating procedures for the reactor protection system be established. Contrary to this requirement, on May 30, 2005, Procedure PPM 2.7.6 was revised, in part, to direct operators in Step 5.9.6 to open disconnect RHR-DISC-V/9 to maintain Valve RHR-V-9 open during shutdown cooling operations versus the correct disconnect RHR-42-8BA2A. Because this finding was of very low safety significance and was entered into the licensee's corrective action program as PER 206-0602, this violation is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy (NCV 05000397/2007002-04; Inadequate Reactor Protection Procedure and Subsequent Inadvertent Isolation of Shutdown Cooling). Energy Northwest implemented immediate corrective actions to revise the affected procedure to direct opening the correct disconnect and plans to perform technical reviews of all shutdown cooling related procedures.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On January 31, 2007, the inspector presented the emergency plan change inspection results to Mr. M. Reis, Supervisor, Emergency Preparedness, who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On March 22, 2007, the inspector presented the occupational radiation safety inspection results to Mr. J. V. Parrish and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On April 9, 2007, the resident inspectors presented the inspection results to Mr. S. Oxenford and other members of his staff, who acknowledged the findings. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

On May 3, 2007, the resident inspectors held a re-exit meeting with Mr. D. Coleman, to present changes in the characterization of a violation identified during the inspection period and presented in the April 9, 2007 exit meeting.

4OA7 Licensee Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy for being dispositioned as an NCV.

- Licensee TS Section 5.7.1.a, requires that each entryway to high radiation areas not exceeding 1.0 rem/hr be barricaded and conspicuously posted as a High Radiation Area. Contrary to this requirement, on two occasions the licensee failed to properly barricade high radiation areas. On September 25, 2006, a swing gate to the entrance to the R-5 sump area in the 422 Reactor Building Control Rod Drive pump room was left open. On the second occasion, February 7, 2007, a portion of the High Radiation Area boundary surrounding the Reactor Water Clean Up Demineralizer 1A was found dangling into the open cubicle leaving that section of the area unbarricaded. These issues were entered into the licensee's corrective action program as CR-2-06-0518, and CR-2-07-01175 respectively. This finding is of very low safety significance because it did not involve a very high radiation area or personnel overexposure.

ATTACHMENT 1: SUPPLEMENTAL INFORMATION

ATTACHMENT 2: SIGNIFICANCE DETERMINATION EVALUATION

ATTACHMENT 1
SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Energy Northwest

D. Atkinson, Vice President, Nuclear Generation
S. Belcher, Manager, Operations
I. Borland, Manager, Radiation Protection
S. Boynton, Systems Engineering Manager
D. Coleman, Manager, Performance Assessment and Regulatory Programs
G. Cullen, Licensing Supervisor, Regulatory Programs
D. Dinger, Supervisor, Radiological Planning
A. Khanpour, General Manager, Engineering
M. Laudisio, Supervisor, Radiological Operations
T. Lynch, Plant General Manager
T. Martens, Health Physics Staff Advisor
W. Oxenford, Vice President, Technical Services
J. Parrish, Chief Executive Officer
M. Reis, Supervisor, Emergency Preparedness
F. Schill, Licensing
M. Shymanski, Radiation Protection Manager, (acting)
K. Webb, Technician, Health Physics
C. Whitcomb, Vice President, Organizational Performance and Staffing

NRC Personnel

R. Cohen, Resident Inspector
Z. Dunham, Senior Resident Inspector

ITEMS OPENED AND CLOSED

Items Opened, Closed, and Discussed During this Inspection

Opened

None.

Opened and Closed

05000397/2007002-01	NCV	Inadequate Clearance Order Results in Inoperable Diesel Generator (Section 1R19)
05000397/2007002-02	NCV	Inadequate Battery Surveillance Test (Section 1R22)
05000397/2007002-03	NCV	Inadequate Immediate Corrective Actions for Electrical Disconnect Deficiency (Section 4OA2.2)
05000397/2007002-04	NCV	Inadequate Reactor Protection Procedure and Subsequent Inadvertent Isolation of Shutdown Cooling (Section 4OA5.2)

Closed

05000397/2006004-02	URI	ASME Code Testing of Service Water Siphon Line (Section 4OA5.1)
05000397/2006005-01	URI	Loss of Shutdown Cooling (Section 4OA5.2)

Discussed

None.

PARTIAL LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures

SOP-COLD WEATHER-OPS; Cold Weather Operations; Revision 5

Section 1R04: Equipment Alignment

Drawings and Diagrams

Drawing E505-1; DC One Line Diagram; Revision 88

Drawing E505-2; DC One Line Diagram; Revision 1

Drawing RHR-897-1.2; RHR Loop "C" From Pump RHR-P-2C Discharge; Revision 11

Drawing D-220-3500-9.0; Tube Erection Isometric For Local Instrument RHR-PS-16C and 19C Reactor Building, Floor Elevation 422' - 3"

Drawing 159C4361; Level Switch; Revision 5

Work Orders and Work Requests

WO 01120761	WO 01047952

Corrective Action Documents

CR 2-07-02093	CR 2-07-01262	CR 2-07-02093	CR 2-07-00980
CR 2-07-00651	CR 2-07-00980		

Miscellaneous

CER C93-0371; Revision 0

CER C93-0372; Revision 0

CER C93-0049; Revision 0

CER C92-0193; Revision 0

CER C93-0049; Revision 0

CER C91-0513; Revision 0

CER C92-0006; Revision 1

Calculation ME-02-95-1; Revision 0; Dated May 19, 1997

Calculation ME-02-84-108; Revision 0; Dated January 25, 1985

Calculation 6.92.05-SXV-12; Revision 0; Dated August 6, 1982

Calculation ME-02-84-81; Revision 0; Dated November 14, 1984

PTL A 256883; RHR-PS-16C and LPCS-PS-9 are making contact with adjacent walls and tubing which could result in excessive switch chatter during SSE; Dated February 20, 2007

FSAR; Chapters 3 and 6

Section 1R05: Fire Protection

Procedures

CGS Pre-Fire Plan; Revision 3

Final Safety Analysis Report; Appendix F

Section 1R12: Maintenance Effectiveness

Work Orders and Work Requests

WO 01105545	WO 01129648

Corrective Action Documents

CR 2-07-00487	CR 2-07-00535	PER 207-0042

Miscellaneous

Calculation ME-02-93-76; Calculation for Cooling Loads for the Control Room Under Normal and Accident Conditions with all Non-Emergency Lighting Turned Off in the Adjacent Areas; January 23, 2004

CER No. C93-0372; Component Classification Evaluation Record; Revision 00

ENW Maintenance Rule Scoping Matrix; Revision 14

System Health Report Columbia Generating Station Control Room HVAC

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

PPM 10.2.73; Freeze Seals Using Liquid Nitrogen as the Freezing Agent; Revision 13

Drawings and Diagrams

Drawing 116D4189; RWCU Heat Exchangers; Revision Dated November 13, 1972

Drawing M526-1; Flow Diagram Fuel Pool Cooling and Clean-up System; Revision 95

Work Orders and Work Requests

WO 01130766	WO 01105545	WO 01102206

Corrective Action Documents

CR 2-07-01522	PER 20x-xxxx

Miscellaneous

Danger Tag Clearance D-FPC-V-108-001, Dated January 30 , 2007

Foreign Material Exclusion Checklist for Work Activity WO 01102206

Core Damage Cut Sets for January 18, 2007

Sentinel Evaluation for January 18, 2007

Technical Specification Inoperable Equipment/LCO/RFO Status Sheet; Log Number 10877, Dated January 18, 2007

Section 1R15: Operability Evaluations

Procedures

PPM OSP-CVB/IST-M701; Suppression Chamber-Drywell Vacuum Breaker Operability; Revision 4

PPM 10.2.53; Seismic Requirements for Scaffolding, Ladders, Man-Lifts, Tool Gang Boxes, Hoists, and Metal Storage Cabinets; Revision 24

Drawings and Diagrams

Drawing EWD-22E-035A; Primary Containment Atmospheric Control System CVB-V-1JK Front Disc; Revision 1

Work Orders and Work Requests

WO 01128167	WO 01102516

Corrective Action Documents

CR 2-07-00941	CR 2-07-01862	CR 2-06-08965	CR 2-07-00189

Miscellaneous

Technical Issues Fact Sheet; RFWT-DT-1B; December 3, 2006

Decision Resolution; December 3, 2006

50.59 Screening 07–0007; January 8, 2007

Clearance D-SLC-RLY-M600B-005; Replace Relay, WO 01123259

Section 1R19: Post Maintenance Testing

Procedures

PPM OSP-ELEC-M703; HPCS Diesel generator Monthly Operability Test; Revision 28

Drawings and Diagrams

Reference Number; Title; Revision or Date of Document

Drawing M-548-1; Flow Diagram HVAC For Control and Switch Gear Rooms Radwaste Building; Revision 93

Work Orders and Work Requests

WO 01126519	WO 01126993	WO 01105673	WO 01106995
WO 01124292	WO 01127924		

Corrective Action Documents

CR 2-07-02273	CR 2-07-01658	PER 207-001	CR 2-06-03322

Miscellaneous

OSP-RCIC/IST-Q701; RCIC System Operability Test; Revision 33

Impact Statement for WO 01130603; Dated February 15, 2007

Equipment Qualification Record Seismic; 256026; Revision 6; Dated December 16, 2003

Operations Night Order 806

Section 1R22: Surveillance Testing

Procedures

OSP-RRC-D701; Jet Pump Operability and Recirculation Loop Flow Mismatch; Revision 8

ISP-FDR/EDR-M401; Drywell Sump Flow Monitors - CFT; Revision 5

OSP-SW/IST-Q703; HPCS Service Water Operability; Revision 9

Work Orders and Work Requests

WO 01127781

Corrective Action Documents

PER 201-0942 CR 2-07-02116

Section 1R23: Temporary Plant Modifications

Procedures

Temporary Modification Request TMR 06-01; Temporarily Remove End Cap Sprinkler Head and Cap; February 6, 2006

Section 1EP6: Drill Evaluation

Drawings and Diagrams

Columbia Generating Station 2007 ERO Drill Team Training Drill; Date March 6, 2007

Columbia Generating Station Operations Department 2007 ERO Drill Team Training Drill Critique; Date March 12, 2007

Section 2OS1: Access Controls to Radiologically Significant Areas (71121.01)

Corrective Action Documents

06-00199, 06-06040, 06-06339, 06-06750, 06-06871, 06-07050, 06-07172, 06-07905, 06-07959, 07-00075, 07-01175, 07-01600

Audits and Self-Assessments

SA-2006-00132006 Annual Review of the Radiation Protection Program

Radiation Work Permits

30001677	Drywell/Undervessel Control Rod Drive Remove and Replace
30001697	Drywell ISI/NDE/EC and Support
30001705	Drywell MSRV Maintenance
30001693	Drywell Health Physics Support

Procedures

SWP-RPP-01	Radiation Protection Program, Revision 6
GEN-RPP-04	Entry into, Conduct in, and Exit from Radiologically Controlled Areas, Revision 14
11.2.7.1	Area Posting, Revision 23
11.2.7.3	High, High High, and Very High Radiation Area Controls, Revision 26
11.2.13.1	Radiation and Contamination Surveys, Revision 16
11.2.18.1	Radiological Control of Radiography Operations, Revision 10

Section 2OS2: ALARA Planning and Controls (71121.02)

Corrective Action Documents

06-05682, 06-06123, 06-06445, 06-06749, 06-08260, 06-09312, 07-00004, 07-00294, 07-00769, 07-01474,

Audits and Self-Assessments

SA-2007-0012Monitoring for Internal Radioactivity

Shielding Requests

Radiation Work Permits

30001357	Maintenance Tasks in Drywell
30001364	Drywell Undervessel Work
30001664	Drywell Work Behind Permanent Shielding on A and B Loops
30001636	Drywell Undervessel Nuclear Instrumentation Inspect/Repair
30001607	Forced Outage Tasks Planned at < 50 mRem/Task
30001360	Drywell Operations Inspections/Surveillances/Line Ups

Procedures

GEN-RPP-01	ALARA Program Description, Revision 6
GEN-RPP-02	ALARA Planning and Radiation Work Permits, Revision 14
GEN-RPP-05	Respiratory Protection Program Description, Revision 7
GEN-RPP-13	ALARA Committee, Revision 5
GEN-RPP-14	Control of Temporary Shielding, Revision 4
HPI-8.8	Supplied-Air Suit Donning and Removal, Revision 0
11.2.11.3	Issuance of Respiratory Protection Equipment,

Miscellaneous

ALARA Committee Meeting Minutes; 07-01, 06-13, 06-10
17th Refueling Outage Final Report
Critique, Forced Outages FO-06-01
Temporary Shielding Packages: 07-05, 07-03, 06-06, and 04-06
Radiological Services Continuous Improvement Plan

Section 4OA1: Performance Indicator Verification

Miscellaneous

Operator Logs

ENW and NRC Performance Indicator Data

NEI 99-02; Regulatory assessment Performance Indicator Guideline; Revision 4

HPI-0.14; Assessing and Reporting NRC Occupational Exposure Control Effectiveness Performance Indicator Data, Revision 4

Section 4OA2: Identification and Resolution of Problems

Procedures

PPM 2.7.13; AC Electrical Breaker Racking; Revision 31

Corrective Action Documents

PER 207-0020	PER 205-0499	PER 206-0603	PER 204-0858

Section 4OA5: Other Activities

Corrective Action Documents

CR 2-06-05951	PER 206-0492	CR 2-06-06306

Miscellaneous

Design Basis Document 309; Standby Service Water System; Revision 8

Columbia Generating Station Inservice Inspection Program Plan; Interval 3

ATTACHMENT 2
SIGNIFICANCE DETERMINATION EVALUATION

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Phase 3 Risk Assessment of Isolation of the Residual Heat Removal System at CGS on November 3, 2006

Probabilistic Risk Assessment (PRA) Analyst:	Jeff Mitman, Senior Reliability and Risk Analyst, NRR/DRA/APOB
Probabilistic Risk Assessment (PRA) Analyst:	Antonios Zoulis, Reliability and Risk Analyst, NRR/DRA/APOB
Probabilistic Risk Assessment (PRA) Analyst:	Russ Bywater, Senior Reactor Analyst R-IV/DRS
Peer Reviewer:	Marie Pohida, Senior Reliability and Risk Analyst, NRO/DSRA/SPLB
Peer Reviewer:	Gareth Parry, Senior Level Advisor for PRA, NRR/DRA

1.0 Introduction

At 0445 on November 3, 2006, Columbia Generating Station (CGS) was shutdown in Mode 4 (Cold Shutdown). The unit was approximately 72 hours into a forced outage with the reactor vessel level being maintained at 70 inches and water temperature was being maintained 114 °F. Operators were performing a procedure to transfer reactor protection system (RPS) B from its normal power supply (RPS MG set) to its alternate power supply. During the procedure, RHR-V-9 (residual heat removal (RHR) shutdown cooling inboard containment isolation valve) closed and shutdown cooling was interrupted. Reactor recirculation pump A remained in service providing forced flow through the core. Operators reopened RHR-V-9 and restored shutdown cooling. Reactor temperature reached 148 °F and vessel level reached 95 'inches' (bottom of main steam lines is 116 inches) while shutdown cooling was not in service. Shutdown cooling was restored in 45 minutes (120 minutes time to boil from 120 °F) after RHR-V-9 went closed. Reactor temperature and level were restored to their previous operating bands by 0451 PST. RHR-V-9 closed due to an error in the controlling procedure.

2.0 Discussion of the Performance Deficiency

The performance deficiency associated with this finding was Energy Northwest's failure to provide an adequate procedure in accordance with Technical Specification 5.4.1.1.a. Specifically, Step 5.9.6 of Procedure PPM 2.7.6, "Reactor Protection System," Revision 23, was inadequate. The procedure directed opening an incorrect electrical disconnect for Valve RHR-V-9. Opening the identified disconnect removed power from the motor operator of Valve RHR-V-9, but did not prevent formation of a sealed-in closure signal when the RPS B power supply was transferred to its alternate supply. Consequently, the valve closed when power was restored to the motor operator. A different electrical disconnect should have been identified that would also have prevented the formation of the sealed-in closure signal. Closure of the valve resulted in an interruption of shutdown cooling.

3.0 Plant Conditions Prior to the Event

- Reactor in cold shutdown with level at 70 inches (this is above the normal operating level of approximately 30 inches but well below the main steam lines)
- Reactor Recirc. loop A inservice
- B RHR inservice in shutdown cooling mode (SDC) with a reactor water temperature of 114 °F
- Division 2 Standby Service Water inservice cooling the B RHR heat exchanger
- Division 3 Standby Service Water unavailable due to maintenance
- High Pressure Core Spray (HPCS) inoperable with control power removed but available if required
- All three condensate pumps available
- Condenser vacuum not available
- Seven of eight MSIVs open but capable of being closed
- Primary containment vented via open personnel airlocks but capable of being closed in 1 to 2 hours. It is our expectation that containment closure would be initiated prior to RCS temperature reaching 200F.

- One of two low reactor level logic channels out of service as allowed by Technical Specifications
- All other equipment operable or available

4.0 Licensee Event Mitigation Capability

The following equipment was available to mitigate the RHR SDC isolation:

- RHR loop A, B and C for low pressure injection. Loop B would have required manual realignment of the suction from the RCS to the suppression pool
- RHR loop A and B for SDC assuming that SDC isolation valve could have been reopened.
- Low pressure core spray (LPCS)
- High pressure core spray assuming the control fuses were reinstalled
- Standby service water RCS injection
- All three condensate pumps
- Fire water system was available but not modeled as the station does not include this system in their procedures
- One train of auto start logic for ECCS logic was operable
- Automatic depressurization system (ADS) was functional
- Containment was open but capable of being closed
- Secondary containment was operable
- Containment venting capability was functional
- Division A and B diesel generators were operable along with their associated distribution systems

5.0 Significance Determination Process (SDP) Phase 2 Summary

The analysts evaluated the finding in accordance with NRC Inspection Manual Chapter (IMC) 0609, Appendix G, "Shutdown Operations SDP," and IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." The conditional core damage probability (CCDP) was the metric used to assess the significance of this event. For a shutdown event, the CCDP is interpreted as the additional core damage frequency incurred by the licensee as a result of the performance deficiency. Inputs and assumptions used in the evaluation were those identified above.

Using Appendix G, Attachment 3, Worksheet 4, "SDP Worksheet for a BWR Plant - Loss of Operating Train of RHR in POS 1 (Head On)," the analysts made adjustments to the remaining mitigation capability credits to reflect equipment availability and time available to complete tasks prior to core damage. The most significant core damage sequence was the loss of the operating train of RHR, followed by failure to recover the RHR function and failure of operators to successfully vent the containment. This sequence had risk significance equal to 7. Therefore, the finding was evaluated for its potential risk contribution due to large early release frequency (LERF) in accordance with IMC 0609, Appendix H. The LERF evaluation identified that because the event occurred while the unit was in Plant Operating State (POS) 1E, the unit had been shutdown for less than 8 days and the containment was not inerted, the LERF factor was 1.0. The basis of a LERF factor of 1.0 comes from NUREG/CR 6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," Revision 1, and reflects that BWRs with de-inerted Mark II containments are vulnerable to hydrogen combustion in POS 1E within 8 days after shutdown. Therefore, the core damage sequence identified above also had a risk significance of 7 with respect to LERP. As described in IMC 0609, Appendix H, this is equivalent to a White finding.

6.0 Initiation of a Phase 3 SDP Risk Assessment

The Shutdown SDP proceduralized in IMC 0609, Appendix G, is a tool used to screen shutdown findings for potential significance. This finding could not be screened as having very low significance using the Phase 2 analysis. Therefore, a Phase 3 SDP risk assessment was requested to be performed by the Office of Nuclear Reactor Regulation (NRR).

On December 12, 2006, NRR analysts and a Region IV senior reactor analyst visited the site to obtain information by reviewing documents and interviewing staff to complete the Phase 3 SDP risk assessment. Staff interviewed included the control room supervisor on shift during the event, the assistant outage manager, and the licensee's probabilistic safety assessment engineer.

The analysts used the following references in preparing the risk assessment:

- Condition Report 2-06-08060
- Columbia Generating Station Technical Specifications
- Problem Evaluation Request 206-0602
- Problem Evaluation Request 203-1866
- Forced Outage FO-06-01 Shutdown Safety Plan, Revision 0
- Forced Outage FO-06-01 Shutdown Safety Plan, Revision 1
- Procedure 1.20.3, "Outage Risk Management," Revision 0
- Procedure 1.16.9, "Forced Outage Management," Revision 12
- Procedure 13.1.1, "Classifying the Emergency," Revision 35
- Procedure 2.7.6, "Reactor Protection System," Revision 23
- Procedure 13.1.1A, "Classifying the Emergency - Technical Basis," Revision 18
- Procedure 4.601.A2, "601.A2 Annunciator Panel Alarms," Revision 17
- Procedure 4.601.A4, "601.A2 Annunciator Panel Alarms," Revision 23
- CGS System Description, "ECCS Introduction," Volume 7, Chapter 1, 3/31/03
- CGS System Description, "Residual Heat Removal," Volume 7, Chapter 4, 9/29/03
- SOP-RHR-SDC, "RHR Shutdown Cooling," Revision 9
- SOP-RHR-SDC-Bypass, "Bypassing RHR Shutdown cooling Isolation Logic in Mode 4 and 5," Revision 2
- SOP-ENTRY-DW, "Personnel Entry into Drywell," Revision 6
- ABN-RHR-SDC-LOSS, "Loss of Shutdown Cooling," Revision 2
- ABN-RHR-SDC-ALT, "Residual Heat Removal Alternate Shutdown Cooling," Revision 4
- EOP 5.2.1, "Primary Containment Control," Revision 16
- CGS Simulator Training Lesson, "LORQ Shutdown Scenario," 3/17/05
- Drawing M521-1, "RHR Loop A," Revision 100
- Drawing M521-2, "RHR Loop B," Revision 102
- Drawing M521-3, "RHR Loop C," Revision 3
- "Accident Analysis of Shutdown Cooling Isolation Using MAAP4," Undated document transmitted via email from G. Cullen (Energy Northwest) to R. Bywater (NRC), 2/8/07

- "Risk Assessment for the Columbia Shutdown Cooling Isolation Event," Undated document transmitted via email from G. Cullen (Energy Northwest) to R. Bywater (NRC), 2/8/07

After the site visit, the analysts completed the Phase 3 risk assessment as described below. The results of the risk assessment were that the finding was of very low safety significance (Green).

7.0 Development of the Model

No Low Power/Shutdown (LP/SD) SPAR model exists for CGS. Therefore, the at-power CGS SPAR model was modified to allow analysis of the isolation of shutdown cooling (SDC) event. A new event tree (ET) was created with an initiating event of SDC isolation. This ET was linked to existing at-power fault trees (FT) or new FTs. The existing FTs were modified as necessary to appropriately describe system dependencies during shutdown conditions and the different success criterion.

HRA Analysis

Shutdown operation is highly dependent on operator actions as most of the required actions are manual (e.g., placing SDC and SPC inservice). In addition, additional analysis was conducted to properly characterize the required manual actions. The dominant human error probabilities (HEPs) in the at-power CGS model, following standard SPAR modeling approach, were contained in the various front-line systems or supporting systems. To ensure appropriate handling of the shutdown analysis, where the human actions are paramount, in most cases the HEPs were placed in an event tree top. All other HEPs were set to "ignore" in a change-set.

The first ET top (SD-SDC-R) contains the operator probability of not recovering the lost SDC loop or of placing the standby loop in operation. The operator cues for this action are those associated with the loss of the running RHR pump (e.g., low RHR system pressure). This action is controlled by the CGS abnormal operating procedure "Loss of SDC" (ABN-RHR-SDC-LOSS) and is expected to be performed by the first crew. The second top (SD-ASDC) addresses the operator actions required to place alternate SDC in-service. Alternate SDC is defined as manually opening a SRV, then filling the RCS with an injection system to above the main steam lines, spilling water through the open SRV to the suppression pool. This process moves the decay heat from the RPV to the suppression pool. This HEP also contains the operator actions to place suppression pool cooling in-service. The cues for this process are RCS temperature approaching the 200 °F. This operation is controlled by the CGS abnormal procedure "RHR Alternate SDC" (ABN-RHR-SDC-ALT) and is also expected to be performed by the first crew.

Another ET top (SD-ECCS) controls the operator actions required to use the CGS EOPs. The cues for this action are the entry conditions into the EOPs, for example low reactor level or possibly high suppression pool temperature. These steps are expected to be controlled by a second crew after a shift turnover. The fourth significant HEP (SDC-XHE-XM-SPC) is contained in the suppression pool cooling FT. This iteration of suppression pool cooling is only used in the sequences containing automatic operation of the ECCS. A separate query on suppression pool cooling is required because to arrive at this branch the procedures assume that manual alternate shutdown cooling has previously failed (which included a previous attempt at initiating suppression pool cooling). The auto actuation of ECCS is expected to occur about 10 hours after loss of shutdown cooling and would thus be controlled by the second crew. The next HEP is for containment venting (CVS-XHE-XM-VENT); it is modeled in the containment venting FT. High containment temperature or pressure will supply the operator cues for this action. This HEP is also controlled by the EOPs. This would be a late action – in the time frame of 20 to 30 hours after the loss of shutdown cooling – and is expected to be performed by a third crew.

The final dominant HEP is labeled HCS-MDP-TM-HPCS. The chosen nomenclature is somewhat misleading. The HPCS control logic had been intentionally disabled by CGS plant personnel to prevent an auto start of the system because the HPSC service water system was unavailable due to maintenance. The HPCS control logic had been defeated to prevent an auto start of the system by removing the control logic fuses. The HPCS system's dependency on the HPCS service water system is two-fold. First, the service water system cools the HPCS diesel. Second, it cools the HPCS pump room cooler. The HPCS diesel would only be required on loss of the division 3 bus for example during a LOOP. This SDP analysis will not analyze this combination of initiating events. The HPCS room cooler is not needed several days after shutdown when decay heat levels are lower. Therefore, the HPCS pump could be run if needed without the HPCS service water system. Thus, HPCS was considered available if needed but was dependent on operator action to restore the control logic to the system. This HEP dependency was modeled and the results input into the existing HCS-MDP-TM-HPCS basic event. This action is assumed to be conducted by the second crew. Table 1 shows a summary of these inputs.

Table 1
Summary of HRA Results

Human Error Event	Description	Time Available	Mean Diagnosis HEP	Mean Action HEP	Total Mean HEP	Controlled by Procedure	Controlled by Ops Crew
SDC-XHE-XM-OPTW1	Operator fails to recover operable SDC Train in TW1	90 mins	1.00E-4	1.00E-3	1.10E-3	Loss of SDC Off-Normal	One
SDC-XHE-XM-ASDC	Operator Initiates Alternate SDC	>6hrs	1.00E-3	1.00E-4	1.10E-3	Alternate SDC Off-Normal	One
SDC-XHE-XM-ECCS	Operator Initiates ECCS	>6hrs	5.00E-2	1.50E-3	5.14E-2	EOPs	Two
HCS-MDP-TM-HPCS	Operator Fails to Restore HPCS from Pull to Lock	>6hrs	1.00E-4	1.00E-4	2.00E-4	EOPs	Two
SDC-XHE-XM-SPC	Operator Initiates Suppression Pool Cooling	>6hrs	1.00E-4	1.00E-4	2.00E-4	EOPs	Two
CVS-XHE-XM-VENT	Operator Fails to Vent Containment	>20hrs	5.00E-3	5.00E-4	5.50E-3	EOPs	Three

In addition to the calculation of specific HEPs for this event, sequences or cutsets which involved failure of multiple post-accident operator actions were examined for human dependency. Such dependency can occur due to a common cue or short/limited time separation between different cues. In addition, performance of a previous action can decrease the time available to perform subsequent actions. The method of identifying dependent operator actions involved reviewing the cutsets that were generated following quantification of the accident sequences. This process looked for and considered combinations of HEPs that included combinations of failures as well as successes.

The dependency between multiple operator actions is shown in Table 2. The approach used to resolve these dependencies follows the method prescribed in the SPAR-H guidance. The analyst deviated from the SPAR-H methodology when considering different crews. The SPAR-H methodology does not provide guidance on the application of zero dependency when considering different crews. For events where time available exceeded 6 hours, different crews were given zero dependency unless the action was 3^{rd} or greater in a series. In the case where the action was the 3^{rd} or greater, then a low dependency was assigned. In addition, zero dependency was given to events that contained intervening successes between failed human actions.

To simplify cutset manipulation, a conditional HEP factor (CHEP Factor) was calculated by dividing the conditional joint HEP by the unconditional joint HEP. The appropriate CHEP Factor was then added to the corresponding cutset.

Table 2
Summary of Conditional HEP Results

COMBINED HUMAN ERROR	Description	APPLICABLE OPERATOR ACTION FAILURES	UNCONDITIONAL JOINT HEP	CONDITIONAL JOINT HEP	CHEP FACTOR [1]
CHEP-ASDC-ECCS	Operator fails to establish Alternate SDC and ECCs	SDC-XHE-XM-ASDC * SDC-XHE-XM-ECCS	5.65E-5	5.65E-5	1
CHEP-SDC-/ASDC-HPCS	Operator fails to establish SDC, is successful with Alternate SDC but fails to restore HPCS	SDC-XHE-XM-OPTW1 * /SDC-XHE-XM-ASDC * HCS-MDP-TM-HPCS	2.20E-7	1.00E-5	45
CHEP-ASDC-/ECCS-HPCS	Operator fails to establish Alternate SDC, transitions to the EOPs but fails to restore HPCS	SDC-XHE-XM-ASDC */SDC-XHE-XM-ECCS * HCS-MDP-TM-HPCS	2.20E-7	1.00E-5	45
CHEP-SDC-/ASDC-VENT	Operator fails to restart SDC, establishes Alternate SDC but fails to vent the containment	SDC-XHE-XM-OPTW1 */SDC-XHE-XM-ASDC * CVS-XHE-XM-VENT	6.05E-6	1.00E-5	1.7
CHEP-ASDC-/ECCS-VENT	Operator fails to establish Alternate SDC, transitions to the EOPs, but fails to vent containment	SDC-XHE-XM-ASDC */SDC-XHE-XM-ECCS * CVS-XHE-XM-VENT	6.05E-6	1.00E-5	1.7
CHEP-SDC-ASDC-ECCS	Operator fails to establish SDC, Alternate SDC and ECCs	SDC-XHE-XM-OPTW1 * SDC-XHE-XM-ASDC * SDC-XHE-XM-ECCS	6.22E-8	1.56E-5	250.8
CHEP-ASDC-ECCS-SPC	Operator fails to establish Alternate SDC, ECCS, and suppression pool cooling	SDC-XHE-XM-ASDC * SDC-XHE-XM-ECCS * SDC-XHE-XM-SPC	1.13E-8	2.83E-5	2504.4
CHEP-ASDC-ECCS-VENT	Operator fails to establish Alternate SDC, ECCS, and subsequent Venting	SDC-XHE-XM-ASDC * SDC-XHE-XM-ECCS * CVS-XHE-XM-VENT	3.11E-7	1.00E-5	32.2
CHEP-SDC-ASDC-ECCS-V	Operator fails to establish SDC, Alternate SDC, ECCs and venting given the automatic start of LPI and ADS	SDC-XHE-XM-OPTW1 * SDC-XHE-XM-ASDC * SDC-XHE-XM-ECCS *CVS-XHE-XM-VENT	3.42E-10	1.00E-5	29239.8
CHEP-SDC-ASDC-ECCS-SPC	Operator fails to establish SDC, Alternate SDC, ECCs and SPC given the automatic start of LPI and ADS	SDC-XHE-XM-OPTW1 * SDC-XHE-XM-ASDC * SDC-XHE-XM-ECCS * SDC-XHE-XM-SPC	1.24E-11	1.56E-5	1.26E+06
CHEP-ASDC-ECCS-SPC-V	Operator fails to establish Alternate SDC, ECCs, SPC and venting given the automatic start of LPI and ADS	SDC-XHE-XM-ASDC * SDC-XHE-XM-ECCS * SDC-XHE-XM-SPC * CVS-XHE-XM-VENT	6.22E-11	1.00E-5	1.61E+05
CHEP-SDC-ASDC-/ECCS-V	Operator fails to establish both SDC and Alternate SDC, transitions to the EOPs but fails to vent containment.	SDC-XHE-XM-OPTW1 * SDC-XHE-XM-ASDC * /SDC-XHE-XM-ECCS * CVS-XHE-XM-VENT	6.66E-9	1.00E-5	1501.5
CHEP-SDC-ASDC-/ECCS-H	Operator fails to establish both SDC and Alternate SDC, successfully transitions to the EOPs but fails to restore HPCS	SDC-XHE-XM-OPTW1 * SDC-XHE-XM-ASDC */SDC-XHE-XM-ECCS * HCS-MDP-TM-HPCS	2.42E-10	1.00E-5	41322.3
CHEP-5[2]	Operator fails, SDC, Alternate SDC, ECCS, and SPC and venting given the automatic start of LPI and ADS	SDC-XHE-XM-OPTW1 * SDC-XHE-XM-ASDC *SDC-XHE-XM-ECCS * SDC-XHE-XM-SPC * CVS-XHE-XM-VENT	6.84E-14	1.00E-6	1.46E+07

[1] Calculated as Conditional Joint HEP divided by Unconditional Joint HEP.

[2] For this HEP, a minimum cutoff of 1E-06 rather than 1E-05 was used based on expansive time available (>20 hours), different crews, and additional cues which would prompt additional recovery actions not modeled in this analysis. See Section 9 for additional discussion.

8.0 Conditional Core Damage Probability (CCDP) Assessment Results

Major Assumptions

The final top in the event tree model is containment venting. For this model it is assumed that all injection methods fail upon failure of the containment. This is a conservative assumption that has significant impact on the analysis results.

CCDP Results

No external events analysis was conducted because this event was operator related resulting from a plant evolution. It was not caused by an external event such as fire, flood, or a seismic initiator.

To calculate the risk significance of this event a CCDP analysis was performed by setting the initiating event frequency and all of the basic event probabilities of equipment unavailable to one and then solving the event tree. This process is consistent with the requirements of Inspection Manual Chapter 609 Appendix G Attachment 3, "Phase 2 Significance Determination Process Template for BWR during Shutdown," step 4.3.8.

The results of the CCDP analysis are shown in Table 3. The truncation limit was set at 1E-16. An uncertainty analysis was also performed with a sample size of 10,000 trials using the Monte Carlo method. Appendix E contains the associated cutsets.

Sequence 20 in the results table below is a unique sequence not only because it contributes the majority of the total CCDP, but because it contains a combination of five operator actions. If no consideration for this combination of HEPs is considered the product of these five HEPs is approximately 6.8E-13 (this is the unconditional joint HEP in Table 2). To accept a combined failure probability of operator actions at this value is un-defendable. The Conditional HEP for this cutset results in a value below 1E-06. In standard HRA analysis, (based on good HRA practices as described in both the ASME PRA Standard; NUREG/CR-6883, "The SPAR-H Human Reliability Analysis Method" and NUREG-1792, "Good Practices for Implementing Human Reliability Analysis") a cutoff of 1E-5 is acceptable and was used in the analysis for most combinations of HEPs. For sequence 20, the analysts determined that a lower value was appropriate based on expansive time available (>20 hours), different crews, and additional cues which would prompt additional recovery actions not modeled in this analysis. For sequence 20 a value of 1E-6 was applied. The results in Table 3 reflect this value.

The cumulative results for all sequences (including the exceptional conditional joint HEP for sequence 20) yields a CCDP of 1.5E-6. Sequence 20 has a CCDP of 1.0E-6 (this is 67 percent of the total) which if accepted would lead to a white finding by itself. As discussed in the assumption section above, no credit is given in the modeling for late injection after containment failure. It is reasonable to expect that multiple injection mechanisms would survive containment failure and would still be available to prevent core damage. The analysts have no means of quantifying this fraction. In the analysts' judgment, if these two conservatisms were removed the corrected CCDP would be less than 1E-6 and the finding would be green.

Table 3
Base Case CCDP and Sequence Contribution Results

Sequence	Sequence Probability	Mean	5th	Median	95th	CLERP Bin[1]
04	4.6E-07	5.1E-07	1.3E-08	2.1E-07	2.0E-06	1
05	7.1E-12	1.4E-11	7.5E-14	2.5E-12	5.6E-11	2
08	7.1E-09	7.3E-09	1.1E-10	2.0E-09	3.1E-08	1
09	6.2E-09	6.4E-09	1.6E-10	2.3E-09	2.5E-08	2
12	1.5E-09	2.0E-09	1.5E-11	2.7E-10	7.4E-09	1
13	4.4E-15	6.4E-15	0.0E+00	8.9E-16	2.6E-14	2
16	1.2E-11	1.3E-11	9.2E-14	1.8E-12	4.3E-11	1
17	1.1E-10	1.2E-10	1.7E-13	2.8E-12	7.0E-11	2
20 [2]	1.0E-06	9.6E-07	2.5E-09	1.6E-07	4.2E-06	1
21	1.6E-10	1.6E-10	7.0E-12	6.1E-11	5.9E-10	2
22	1.1E-09	1.1E-09	3.3E-11	3.5E-10	4.1E-09	2
TOTALS =	1.5E-06	1.6E-06	3.0-07	4.8E-07	6.2E-06	N/A

Note 1: See Section 9 for a discussion of LERF Bins
Note 2: This sequence value can not be taken at face value. It is very conservative, see discussion above for how it is addressed.

9.0 Conditional Large Early Release Probability (CLERP) Assessment

The figure of merit for this analysis is conditional large early release probability (CLERP). This CLERP analysis is based on the method for shutdown described in NUREG/CR-6595 Revision 1, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," dated 10/2004. This report supplies simplified containment event trees (CET) to determine if the core damage sequence contributes to LERF. NUREG/CR-6595 presents its analysis in terms of LERF, which is interpret here as CLERP.

NUREG/CR-6595 defines LERF as "... the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there is a potential for early health effects." This is identical to the definition of LERF in IMC 0609 Appendix H. Figure 4.5 from NUREG/CR-6595 is applicable to the CGS event. The analysts proceeded to answer the NUREG/CR-6595 CET top questions and evaluated the CET.

From this analysis, the analysts conclude that at least 98 percent of the CCDP leads to CLERP. In Appendix C.5 (Lessons Learned and Recommendations) of NUREG/CR-6595 there is a discussion titled "Loss of Containment Heart Removal (CHR) and TW Sequences." The following is from that discussion:

> These sequences are typically defined by containment failure caused by loss of CHR which in turn causes loss of coolant injection and ultimately core damage. Both containment failure and core damage could occur many hours after the initiating event. However, core damage could occur shortly after containment failure. ... These sequences should be categorized as potentially leading to LERF even though the time of containment failure is late. ... Therefore, the burden is on the utility to demonstrate an effective emergency evacuation procedure for such TW scenarios before assuming that they will not result in early fatalities.

To reach a conclusion on the CLERP issue the analysts considered the following insights: 1) The majority (98 percent from the analysis) of the core damage risk occurs from failure of the injections systems caused by containment failure, 2) In this scenario the containment failure would occur at least 20 hours after the loss of shutdown cooling, and 3) The close-in population at CGS is small and therefore, the authorities can quickly evacuate them. The analysts based on these insights and recognizing that the CCDP is less than 1E-6; conclude that CLERP is less than 1E-7. Therefore, this is a green finding.

10.0 Comparison with the Licensee's Results

The licensee does not currently have a shutdown internal events or a shutdown Level 2 PRA. At the time of the site visit the Phase 2 analysis indicated that the CCDP was 3.6E-7 and that the "LERF" multiplier was one yielding a CLERP also of 3.6E-7. During the site visit CGS personnel did not question the conclusion of the CCDP analysis. However, they did respond to the CLERP results.

The licensee discussed an analysis of the time required for containment failure following a reactor scram from 100 percent power. They considered this a bounding analysis for the November 3rd event. The calculation determined the time for decay heat to increase the temperature of the suppression pool to 110 °F, 275 °F, 345 °F and the time for containment pressure to reach the failure point of 121 psig with no containment cooling, and with HPCS auto starting on RPV level 2. Other plant conditions input into their analysis include: MSIVs close at 38 seconds, RHR heat exchangers A & B locked off, no CRD flow, no fan coolers in operation, all ADS valves lost at a containment pressure of 62 psig, and no containment venting. It concluded that containment failure occurs at 27.67 hours after the scram. As stated above, the licensee considers this calculation to be bounding for the event that occurred on November 3. Based on this calculation the licensee concluded that any core damage event occurring after the November 3rd event was, by definition not a LERF event. (It should be noted that contrary to the assumptions in this analysis, no HPCS pump was running during the event and that the HPCS pump was not capable of an auto start during the event. Also, prior to the event the containment personnel hatch was open. This effectively removes primary containment as a barrier to release. However, CGS procedures require closure of containment under these conditions prior to reaching 200°F in the RCS. These facts have the potential to change the timing of containment failure derived by this calculation.)

Based on the CLERP discussion in Section 9 and the differences cited between the CGS "bounding" analysis and the actual plant conditions, the analysts find the CGS conclusions based on the bounding analysis are not adequately defended.

Subsequent to the site visit, CGS personnel have conducted additional PRA analysis and submitted this analysis to the NRC for our consideration via an email from Greg Cullen (CGS Licensing Manager) to Russ Bywater dated 02-08-2007. They conducted a CCDP analysis using the following:

CCDP = [event probability] * [un-recoverability] * [mitigating system unavailability]

Where:

Event probability = 1
Un-recoverability = 1E-2
Mitigating system unavailability = 1.85E-10

or

CCDP = 1.85E-10

The CGS analysis then determined that ΔCDF = CCDP, and that ΔCDF = ΔLERF.

The CGS analysis evaluates only one of many potential core damage sequences. This one sequence is comparable to sequence 5 from Table 3 (for sequence 5 the analysts calculate a somewhat lower failure probability). The CGS analysis does not address the other potential sequence including the most probable sequences including multiple human actions.

The analysts concluded that the CGS analysis did not analyze all potential core damage and large early release sequences and therefore is incomplete.

11.0 Sensitivity Analysis

Several sensitivity cases were conducted to further understand the event. The cases are described below.

Case 1: All HEPs Set to Zero

This sensitivity case assumed that the operators are perfect and never fail. It was calculated by setting all HEPs to zero. The calculated CCDP was 6.4E-8.

Case 2: Conditional HEPs Set to One

This sensitivity case removes dependency between HEPs from the model. It was calculated by setting all conditional HEPs to one. The calculated CCDP was 4.8E-7.

Case 3: Equipment Availability Set to Technical Specification Minimum

This sensitivity case assumed that only the technical specification mode 4 (cold shutdown), minimum equipment is available. This includes both the division one and two RHR, which satisfies both the injection requirement and the shutdown cooling requirement, and one diesel generator. All other safety related and non-safety related equipment were failed. The failed equipment list included: HPCS, LPCS, all condensate pumps, condensate transfer, standby service water cross inject to RPV, LPCI-C, ADS, CRD, SPC, SRVs, and containment venting. The calculated CCDP was 7.4E-3.

Case 4: Operator Leaves Containment Personnel Hatch Open

As discussed above, at the start of the event the containment personnel hatch was open. Procedurally, prior to exceeding an RCS temperature of 200 °F, the operators were directed to close containment. If the personnel hatch was left open then containment would remain vented throughout the event. The final top event in the in the ET, tested the failure probability of containment venting. If the hatch was left open, this probability was zero. This change-set tested this scenario by leaving the hatch open. The calculated CCDP was 7.6E-9.

Case 5: Automatic Actuation of ADS is Disabled

The final case assumed that the automatic depressurization system (ADS) was not functional. The calculated CCDP was 1.7E-5.

12.0 Evaluation of impact of increased CGS SDC Isolation Initiating Event Frequency

The licensee has experienced four losses of SDC in the last five years. The analysis summarized in Section 8.0 was performed consistent with the NRC's SDP methods which generally limit time of consideration to one year. In order to provide risk insight into the additional contribution of these multiple events, the analysts performed the below additional evaluation. This additional analysis was performed to provide additional risk perspective from an increased initiating event frequency. There was no performance deficiency identified involving an increase in frequency of these events.

Between 2000 and 2005 (inclusive) CGS had an average capacity factor of about 87 percent. Applying this capacity factor to the events gives:

4 events / [(5 years) (1 - 0.87 capacity factor)] = 6 events per shutdown year

This equates to 6.8E-4 per shutdown hour. The industry average IEF for BWR SDC isolations is 1.1E-4 per shutdown hour from EPRI 1003113 (An Analysis of Loss of DHR Trends and IEF (1989 – 2000), dated 11/2001. See Table 7-3 on page 7-5). The CGS IEF is approximately five times higher then the industry's average. The rest of this evaluation will consider the impact of this increased IEF. From general PRA knowledge:

$$CDF = IEF \times CCDP$$

For the specific case under analysis at CGS:

$$CDF_{LSDC} = IEF_{LSDC} \times CCDP_{LSDC}$$

For a base case analysis using the previously described CCDP analysis it is known that the CCDP for the loss of SDC event at CGS was approximately 1E-6. Substituting into this equation this CCDP and the above IEF from EPRI (1.1E-4 per shutdown hour):

$$\begin{aligned} CDF_{LSDC}\,(\text{base}) &= (1.1\text{E-}4/\text{hr.}) \times (1\text{E-}6) \\ &= 5.5\text{E-}11/\text{hr.} \\ &= 9.6\text{E-}7/\text{yr.} \end{aligned}$$

Let's define the above as the base case CDF_{LSDC} frequency. We performed a parallel analysis using the actual IEF at CGS.

$$\begin{aligned} CDF_{LSDC}\,(\text{actual}) &= (6.8\text{E-}4/\text{hr.}) \times (1\text{E-}6) \\ &= 3.4\text{E-}10/\text{hr.} \\ &= 6.0\text{E-}6/\text{yr.} \end{aligned}$$

Finally, from general PRA knowledge, that:

$$\Delta CDF = CDF_{LSDC}\,(\text{actual}) - CDF_{LSDC}\,(\text{base})$$

Substituting in the above calculated values the analysts derive an actual delta CDF for CGS.

$$\Delta CDF = (6.0E\text{-}6/yr.) - (9.6E\text{-}7/yr.)$$
$$= 5.0E\text{-}6/yr.$$

This Section 12.0 evaluation provides additional insights beyond standard SDP methods that an increase in frequency of loss of SDC initiating events can add significantly to the baseline risk of the facility. Although the safety significance of the November 3, 2006, loss of SDC event was determined to be very low (Green), the event was a learning opportunity to re-emphasize the importance of outage risk management and to reduce the likelihood of these events. This perspective was communicated to the licensee by NRC management during the annual assessment of safety performance public meeting on May 1, 2007.